RI 8914

Bureau of Mines Report of Investigations/1984

Effect of Drilling Fluids on Permeability of Uranium Sandstone

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UNITED STATES DEPARTMENT OF THE INTERIOR

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William P. Clark, Secretary

BUREAU OF MINES
Robert C. Horton, Director

Library of Congress Cataloging in Publication Data:

Ahlness, Jon K

Effect of drilling fluids on permeability of uranium sandstone.

(Report of Investigations ; 8914)

Bibliography: p. 13.

Supt. of Docs. no.: I 28.23:8914.

1. Uranium mines and mining. 2. Sandstone. 3. Rocks–Permeability. 4. Drilling muds. I. Johnson, D. I. (Donald I.). II. Tweeton, Daryl R. III. Title. IV. Series: Report of investigations (United States. Bureau of Mines) ; 8914.

TN23.U43 [TN490.U7] 622s [622'.34932] 84-600193

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UNIT OF MEASURE ABBREVIATIONS USED IN THIS REPORT

cm	centimeter	L/min	liter per minute
cP	centipoise	lb	pound
ft	foot	lb/bbl	pound per barrel
ft/yr	foot per year	lb/gal	pound per gallon
g	gram	m	meter
gal	gallon	m/s	meter per second
gal/min	gallon per minute	min	minute
h	hour	mL	milliliter
in	inch	pct	percent
kg/m^3	kilogram per cubic meter	psi	pound per square inch
kPa	kilopascal	rev/min	revolution per minute
L	liter	s	second

EFFECT OF DRILLING FLUIDS ON PERMEABILITY OF URANIUM SANDSTONE

By Jon K. Ahlness,[1] Donald I. Johnson,[2] and Daryl R. Tweeton[2]

ABSTRACT

The Bureau of Mines conducted laboratory and field experiments to determine the amount of permeability reduction in uranium sandstone after its exposure to different drilling fluids. Seven polymer and two bentonite fluids were laboratory-tested in their clean condition, and six polymer fluids were tested with simulated drill cuttings added. Sandstone cores cut from samples collected at an open pit uranium mine were the test medium. The clean fluid that resulted in the least permeability reduction was an hydroxyethyl cellulose polymer fluid. The greatest permeability reduction of the clean polymers came from a shale-inhibiting synthetic polymer. Six polymer fluids were tested with simulated drill cuttings added to represent field use. The least permeability reduction was obtained from a multipolymer blend fluid.

A field experiment was performed to compare how two polymer fluids affect formation permeability when used for drilling in situ uranium leaching wells. For this test, the polymer fluid with the best laboratory results (multipolymer blend) was compared with a commonly used polymer fluid (guar gum) that gave poorer laboratory results. When fluid injection rates for the four wells drilled with the guar gum were compared with those for the four drilled with the multipolymer blend, no statistically significant difference was found.

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INTRODUCTION

The Bureau of Mines is conducting both in situ leaching and hydraulic borehole (or slurry) mining research. This research was described by Olson (1).[3] The work described in this paper is a part of that research.

Good well design is essential to successful in situ uranium leaching. One common problem is low permeability in the formation which surrounds the well, sometimes caused by drilling fluid that was not thoroughly flushed out during well development. This results in low injection rates for the well. The seriousness of the problem was demonstrated in the Bureau's first field study of in situ uranium leaching, where the wells had such low injection rates that the pilot test was invalid. Not enough lixiviant could be injected to test the leach effectiveness. Even when wells with low injection rates can be used, it adds to the cost of leaching.

Formation damage during drilling can be minimized by proper selection and use of drilling fluids. Fluids adequate for exploration boreholes are not necessarily adequate for drilling development wells. For example, bentonite drilling fluids with no polymer additives leave a thick wallcake, which is difficult to remove during well development and which inhibits fluid flow. A popular substitute is guar-gum-based drilling fluid. The advantage claimed is that guar gum is broken down by enzymes several days after hydration to form simple sugars, which are easier to flush out of the well than bentonite. However, the Bureau has found that guar gum drilling fluids do not always break down as quickly as desired. For example, at one field site pieces of guar gum that had not broken down were airlifted from wells 2 weeks after drilling.

Previous, related research on drilling fluids was performed by Tuttle and Barkman (2). Their laboratory tests showed that guar gum drill fluids reduced permeability by a factor of as much as four when injected into high-permeability sandstone. This damage could not be corrected by enzyme breakers or acid hydrolysis. Even guar gum that had already been broken down by enzymes caused large permeability losses. Polymer-based drill fluids such as polyoxyethylene or hydroxyethyl cellulose, with calcium carbonate as a bridging material, were found to be least damaging.

The Bureau's first publication (3) on leaching wells described well problems and cures that the Bureau had investigated. The publication was intended primarily for companies new to in situ leaching, to help them learn from the mistakes and successes of others. An update was included in a later publication (4).

Very little other information about in situ leaching wells has been published. Thiede and Walker (5) made a valuable contribution by describing the findings of Mobil Oil Co. during several years of experience with leaching wells.

Well completion techniques are also described in a Bureau of Mines publication (6) on the state of the art of in situ leaching.

Some relevant literature concerning water wells is available. For example, the Johnson Division of Universal Oil Products Co. published a comprehensive book (7) on water well planning and construction, ground water movement and chemical characteristics, well testing, screen selection, well drilling and development, and pumps. Techniques suitable for water wells are not necessarily suitable for in situ leaching applications, since lixiviants are far more corrosive than ordinary ground water.

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[3]Underlined numbers in parentheses refer to items in the list of references preceding the appendix.

This report describes recent research in drilling fluids for in situ leaching applications. The loss of permeability in sandstone core material caused by several types of drilling fluids was determined in laboratory experiments. These tests were conducted on fluids in both "clean" and "dirty" (simulated drill cuttings added) conditions. A drilling experiment was also conducted at an in situ uranium leaching site. Two drilling fluids were tested, a commonly used guar gum and a "multipolymer blend" which gave good results in the laboratory tests. Each fluid was used in the drilling of four wells. Data obtained from the wells are compared.

ACKNOWLEDGMENTS

The authors wish to thank the Shell Development Co. of Houston, TX, for the drawings of the permeability test cell, Harland Kuhlman of the Bureau's Twin Cities Research Center for his expertise in designing the rest of the permeability test apparatus, and the following companies for donating drilling fluid samples for laboratory testing: Johnson Division of Universal Oil Products of St. Paul, MN; Petroleum Associates of Lafayette, Lafayette, LA; Kelco Division of Merck & Co., Inc., Houston, TX; and American Mud Co., Casper, WY.

A special thanks goes to Rocky Mountain Energy Co. for the samples collected from the Bear Creek Mine and the cooperation received during the field test at the Nine Mile Lake uranium leaching site.

BACKGROUND

DRILLING FLUID FUNCTIONS

Uranium in situ leaching wells are most commonly drilled by the rotary method, which involves rotating a drill bit with a hollow pipe. A fluid is pumped down through the rotating pipe and returns to the surface in the annular space between the outside of the pipe and the hole wall.

This drilling fluid is required to perform the following functions (1, 8-9, pp. 14-16):

1. Remove cuttings from the hole, and allow them to settle in mud pits on the surface.

2. Cool and lubricate the drill bit and string.

3. Prevent the hole from caving.

4. Minimize fluid loss to the formation.

5. Leave minimum amounts of solid residue in the form of wallcake in the wellbore.

The last two functions are the important ones with regard to formation damage and will be discussed in a later section.

DRILLING FLUIDS AVAILABLE

World Oil's "Guide to Drilling, Workover and Completion Fluids" (10) lists many companies that produce drilling fluids and additives. Many products are for oil well drilling or other specialized uses and are not applicable to the specific needs of the in situ uranium leaching industry. The applicable drilling fluids are either bentonites or polymers, some of which may require special additives.

Bentonite

Bentonite is an inorganic gel-forming clay colloid, with the predominant clay mineral being montmorillonite. This material is readily dispersible in water and forms a permanent viscous suspension (11). This suspension is thixotropic. It controls filtrate loss to the formation by forming an impermeable cake of clay particles on the well's wall.

Many companies market bentonite drilling fluids. Products range from sub-bentonite to high-yield bentonite. The differences are due to the grade of the original bentonite deposit and any subsequent upgrading of the material before packaging. A higher grade will require fewer pounds of material to obtain a specified viscosity.

Polymers

A polymer is a molecule formed by the union of two or more identical smaller molecules, the resulting compound having a molecular weight larger than, and chemical properties different from, any of the original components (9, p. 11). Polymers are divided into three categories: natural, synthetic, and semisynthetic. Natural polymers are processed organic materials; starch is an example. Synthetic polymers are manufactured entirely from manmade materials, and semisynthetic polymers are altered natural materials. Most of the polymer drilling fluid products fall into this third category and can be derived from a variety of sources. Some of the most common types are guar gum, xanthum gum, carboxymethyl cellulose (CMC), hydroxyethyl cellulose (HEC), and various combinations and blends of polymers and copolymers whose exact chemistry is proprietary.

Polymer drill fluids are low-solids systems. Fluid density is normally less than 9 lb/gal (1,100 kg/m^3) and total solids are kept below 10 pct. Low solids increase the penetration rate and keep particle buildup on the wellbore to a minimum. Polymers control filtration loss by forming a network of polymer chains on the wellbore. Their vicosity can be broken down with a breaker--an enzyme or a chemical that converts the large polymer molecules to low-molecular-weight polymers and simple sugars. Some polymers are also susceptible to viscosity breakdown from bacterial action.

Certain polymers can be combined with bentonite fluids to beneficiate the bentonite and to improve its suspending and wall-building properties (5).

PERMEABILITY PROBLEMS

Drilling operations damage a formation by decreasing its permeability in the area immediately surrounding the well. This damage occurs by two methods. The first is the blocking of the pore openings when fine particles (wall cake) from the drilling fluid build up on the hole wall (12-13). These particles can be either those used to prepare the fluid, such as bentonite, or drill cuttings.

The second method of damage results from the effects of the drilling fluid filtrate on the fine formation particles (12-13). The filtrate can transport the fines in a formation until they bridge and plug pore openings, or water-sensitive clays may hydrate and swell.

The result of these occurrences is the narrowing or plugging of the pore spaces through which fluids can flow, either on the wellbore surface or deeper in the formation (14). This decreases the well's efficiency, reducing the production and injection rates that can be achieved and that are critical to a successful operation. Some of this damage can be corrected by various methods, such as surging, jetting, airlifting, or acidizing, but these methods are costly and cannot reverse all the damage. Therefore, drilling fluids that will minimize damage should be used.

LABORATORY TESTS

SANDSTONE CORE SAMPLES

Sandstone samples were collected from Rocky Mountain Energy's Bear Creek open pit uranium mine near Bill, WY. They were taken from newly exposed waste material from the pit floor. The quartz sandstone was relatively clean, with the clay size fraction being less than 2 pct. The accessory minerals in the clay size fraction were identified as chlorite, muscovite, and sericite. Cores were cut approximately 1 in (2.54 cm) in diameter and 1 in (2.54 cm) long with air as the drilling medium. The length was limited because the sandstone was quite friable, especially in the coarser grain sizes. The grain size among the cores varied quite a bit, which gave a wide range of initial permeabilities. The orientation of the core axes relative to the original bedding planes was random, which may also have contributed to the wide range of initial permeabilities.

TEST APPARATUS

The laboratory drilling fluid test equipment (fig. 1) consisted of a permeability test cell, two drill fluid tanks, a brine tank, a breaker tank, and the tubing, valves, and fittings necessary to transport and control the fluids from the tanks to the cell. The test apparatus was made of stainless steel. Nitrogen pressure was used to circulate the fluids to the cell.

The permeability test cell (fig. 2) accommodated 1-in (2.54-cm) diameter cores up to 4 in (10.2 cm) long. The core was placed inside a length of shrink tubing between the head assembly and the piston and sealed with O-rings. Oil pressure was used to confine the core.

EXPERIMENTAL PROCEDURE

Drilling fluids were laboratory-tested in both clean and dirty conditions. The fluids were mixed in 3.2-gal (12-L) batches with a small electric mixer. Mixing was done for a minimum of 1 h to allow the fluids to viscosify (hydrate). Dirty fluids were made by mixing Rev-Dust[4] (a low-grade bentonite material) with a hydrated clean fluid. Mixing was continued for 30 min after the addition of the Rev-Dust. The dirty fluid was then allowed to stand overnight to let the excess solids settle out in the mixing container. The settled solids were dried and weighed to determine the solids remaining in the fluid. The fluid was

[4]Reference to specific products does not imply endorsement of the Bureau of Mines.

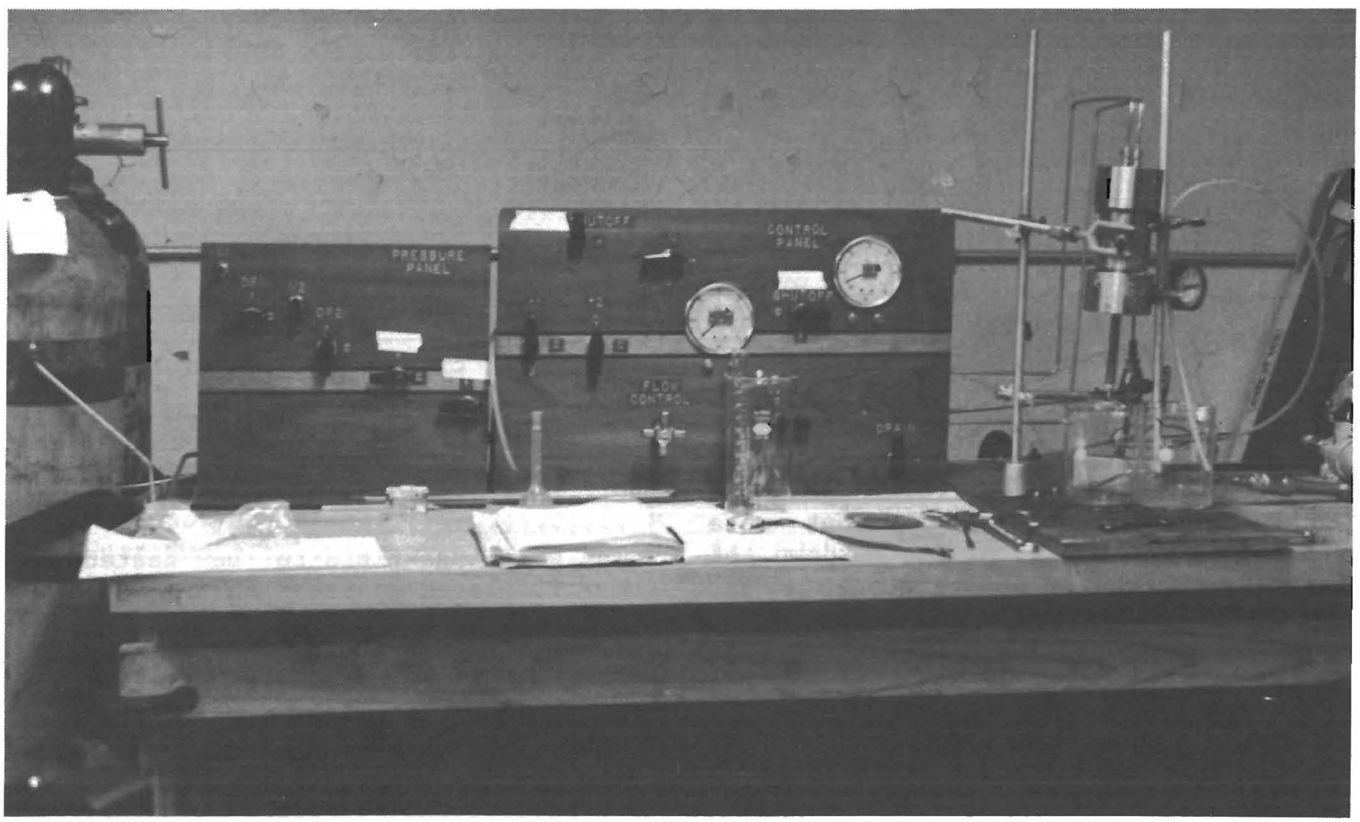

FIGURE 1. - Test apparatus.

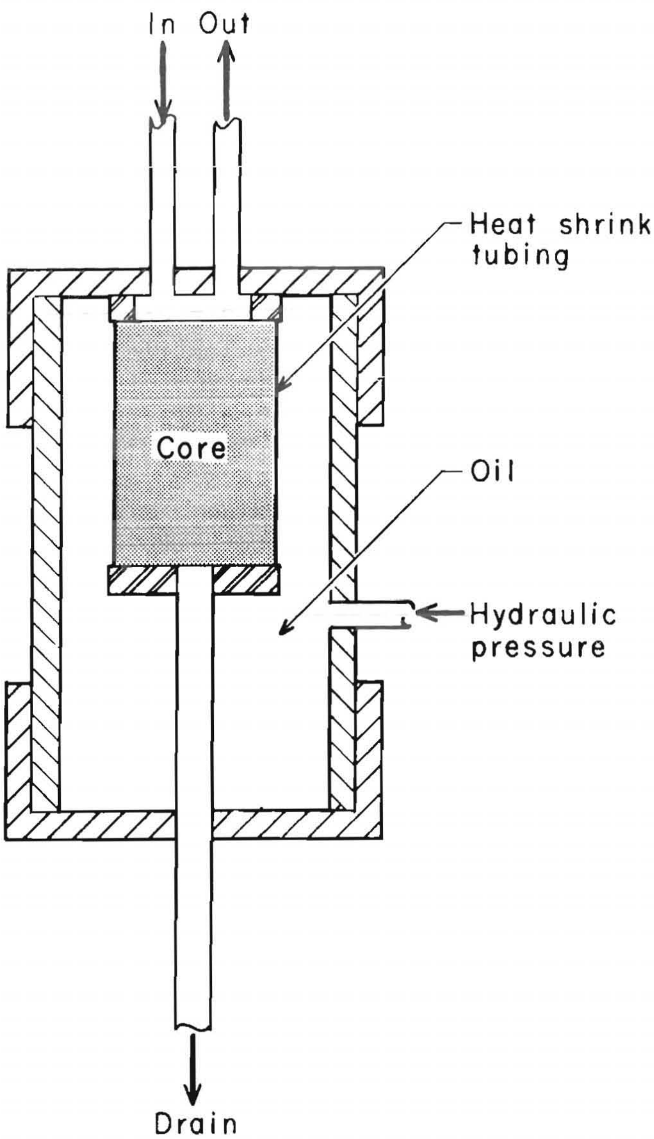

FIGURE 2. - Permeability test cell.

then transferred to the drilling fluid tanks of the test apparatus.

Each fluid was used for a series of tests over a period of 5 to 12 days. Formaldehyde was added (0.2 pct) to preserve the polymer fluids that were susceptible to natural breakdown of viscosity. Even with this precaution, breakdown did occur in some fluids, resulting in decreasing viscosity from one test to the next. Each test was run in the following sequence:

1. Core mounted in the cell.

2. Initial permeability test.

3. Circulation of drilling fluid.

4. Circulation of breaker (if any).

5. Overnight breakdown time (for most tests).

6. Backflush with brine.

7. Final permeability test.

The core sample was placed in a beaker of 3 pct sodium chloride (NaCl) brine and then put in a vacuum chamber to saturate it. The brine inhibited the hydration of any swelling clays that may have been present. The core was then mounted in shrink tubing, and the cell was pressurized to 300 psi (2,068 kPa) for confinement. An initial permeability test was run by forcing brine through the core at 50 psi (345 kPa) and measuring the time required to collect 0.013 gal (50 mL).

Permeability was calculated by the following equation (15, p. 177):

$$k = \frac{V\mu L}{Apt},$$

where k = permeability,

V = fluid volume passed through core,

μ = fluid viscosity,

L = core length,

A = cross-sectional area,

p = pressure,

and t = time.

The drilling fluid to be tested was then circulated past one end of the core at 50 psi (345 kPa), as shown in figure 2, for 1 h. This circulation procedure simulated the dynamic, downhole conditions present during drilling. After the drilling fluid was circulated, the appropriate breaker, mixed in brine, was circulated past the core face at 50 psi (345 kPa) for 10 min. An overnight breakdown time was then allowed. When a breaker was not recommended for a fluid, brine only was circulated. For some breakerless tests an overnight rest was used to be consistent; in others the rest of the test followed immediately.

The next step was to force brine through the core in the reverse direction (backflush). This backflushing was done at a pressure of 75 psi (517 kPa) for 10 min to simulate well development by pumping. Next a second permeability test was run, and finally the core was discarded. The pressures and times selected allowed fluid flow to stabilize in all phases of the test.

LABORATORY TEST RESULTS

CLEAN DRILLING FLUIDS

Seven different polymer fluids, a bentonite, and a bentonite-polymer combination were tested in their clean state. Table 1 shows the types of fluids, the quantities used, the resulting initial viscosities measured immediately after mixing, and the approximate cost per barrel. The quantity and decision on using a breaker were determined from the manufacturer's literature.

The test data are shown in table A-1 (appendix) and are summarized in table 2. Results are given in the form of the "return permeability," the ratio of the final to initial permeability, given as a percent. (This can be interpreted as the percentage of the original permeability remaining after the core's exposure to the drilling fluid.)

TABLE 1. - Clean drilling fluid data

Drilling fluid	Conc, lb/bbl	Initial Fann viscosity, cP at 300 rev/min	Cost per barrel (March 1981)
Hydroxyethyl cellulose............	2.1	60	$13.36
Multipolymer blend................	2.1	44	12.05
Guar gum 1........................	2.1	44	7.56
Bentonite + hydroxyethyl cellulose	([1])	43	2.55
Graft chain polysaccharide........	1.8	37	9.43
Guar gum 2........................	1.7	29	7.17
Xanthum gum.......................	1.4	17	12.48
Synthetic polymer.................	1.0	16	2.53
Bentonite.........................	15.1	6	1.64

[1]Bentonite concentration, 7.0 lb/bbl; hydroxethyl cellulose, 0.4 lb/bbl.

TABLE 2. - Summary of clean fluid permeability tests

Drilling fluid	Number of tests	ARP,[1] pct	Std dev, pct
Hydroxyethyl cellulose............	7	47	10
Multipolymer blend................	9	36	9
Guar gum 1........................	14	17	6
Bentonite + hydroxyethyl cellulose	6	6	6
Do.[2]............................	7	9	6
Graft chain polysaccharide........	8	38	24
Guar gum 2........................	5	23	5
Xanthum gum.......................	12	44	24
Synthetic polymer.................	5	5	3
Bentonite[2]......................	9	27	14

[1]Average return permeability.
[2]1-day test.

The highest average return permeabilities (ARP) were achieved from the HEC (47 pct) and the xanthum gum (44 pct) fluids. The latter results, however, were the most variable and had a standard deviation of 24 pct. The lowest ARP's were obtained from the synthetic polymer (5 pct), the bentonite-polymer combination (6 and 9 pct), the two guar gum fluids (17 and 23 pct), and straight bentonite (27 pct). Two groups of tests were run on the bentonite-polymer fluid: six with an overnight wait, and seven in 1 day. This second set resulted in a slightly higher ARP of 9 pct.

DIRTY DRILLING FLUIDS

Six different polymer fluids were tested with simulated drill cuttings (Rev-Dust) added. The same amount of Rev-Dust 1.4 lb (637 g) was added to each 3.2-gal (12-L) batch of fluid and should have resulted in a 5-pct solids content. However, some settlement occurred when the fluid stood overnight, resulting in some variability. The types of fluids, additive concentration used, percent solids, and viscosities are shown in table 3.

TABLE 3. - Dirty drilling fluid data

Drilling fluid	Conc, lb/bbl	Solids, pct	Fann viscosity, cP at 300 rev/min
Hydroxyethyl cellulose....	2.1	4.0	60
Multipolymer blend........	2.1	4.9	48
Guar gum 1....	2.1	4.4	39
Guar gum 3....	2.1	2.3	39
Xanthum gum...	1.5	5.0	21
Synthetic polymer......	1.0	2.9	13

The test procedures, fluid mixing, and use of breakers were the same as those for the clean fluid tests. The test data are shown in table A-2 and summarized in table 4. The highest ARP was obtained from the multipolymer blend (43 pct). The lowest ARP results were from guar gum 3 (6 pct), xanthum gum (7 pct), and the synthetic polymer (7 pct).

TABLE 4. - Summary of dirty fluid permeability tests

(Five tests per fluid unless otherwise indicated)

Drilling fluid	Solids, pct	ARP,[1] pct	Std dev, pct
Hydroxyethyl cellulose..........	3.96	25	16
Multipolymer blend..	4.91	43	6
Guar gum 1..........	4.36	26	14
Guar gum 3..........	2.27	6	5
Xanthum gum.........	5.00	7	2
Synthetic polymer (4 tests).........	2.92	7	4

CLEAN AND DIRTY FLUID COMPARISONS

Five fluids were tested in both clean and dirty conditions. Table 5 compares their ARP's, average initial core permeabilities, and initial viscosities. The ARP increased for the dirty multipolymer blend and guar gum 1 when tested with Rev-Dust added. The dirty HEC and Xanthum gum ARP's decreased, and the synthetic polymer results were approximately the same. A decrease in ARP would be expected from the dirty fluids. The reasons for the increases in the multipolymer blend and guar gum 1 are not readily discernible. They are not drastic and could be related to experimental error or to variations in core permeability. The fluid viscosities were approximately the same for both the clean and dirty tests and should not have affected the results.

TABLE 5. — Clean and dirty fluid test comparisons

Drilling fluid	ARP,[1] pct		Average initial core permeability, darcy		Initial fluid viscosity, cP	
	Clean	Dirty	Clean	Dirty	Clean	Dirty
Guar gum 1............	17	26	0.2436	0.0539	44	39
Multipolymer blend....	36	43	.1936	.0842	44	48
Hydroxyethyl cellulose	47	25	.0448	.0687	60	60
Xanthum gum...........	44	7	.2510	.0685	17	21
Synthetic polymer.....	5	7	.0590	.0211	16	13

[1]Average return permeability.

FIELD TEST

To check the laboratory results in the field, two of the polymer drilling fluids were tested in eight in situ uranium leaching injection wells. The two fluids selected were guar gum 1 and the multipolymer blend. The guar gum was chosen because it is commonly used in such leaching wells. The multipolymer blend was chosen because it gave good laboratory results in the clean state and the best result in the dirty state.

TEST SITE

The field test was conducted at Rocky Mountain Energy's Nine Mile Lake site about 9 miles north of Casper, WY. The test was done in the upper sand of the Teapot Sandstone. This sandstone is medium to fine grained and contains quartz (>90 pct), feldspar (<5 pct), and minor amounts of mica, glauconite, carbonaceous fragments, and argillaceous material. Most of the feldspar has degraded to kaolinite, which is present in amounts ranging from 2 to 5 pct. The average site permeability is 0.98 darcy. The upper sand ore body is at a depth of 447 ft (136 m) and is overlain by the Lewis Shale.

WELL CONSTRUCTION

Eight injection wells and one production well were drilled in an overlapping five-spot pattern (fig. 3); this is a standard pattern with an additional injection well beyond each corner well in a line with the center well. The distance from the center production well to the inner injection wells was 35 ft (10.7 m) and to the outer wells 50 ft (15.3 m). The two drilling fluids were alternated between the inner and outer injection wells (fig. 3). The production well was not included in the tests to evaluate the fluids.

The wells were constructed and completed in the following manner:

1. A 5-1/8-in (13.0-cm) pilot hole was drilled to within 5 ft (1.5 m) of the ore body.

2. NX-size core was taken through the ore body.

3. The hole was reamed to 7-3/8 in (19.0 cm) to the top of the ore body.

4. PVC plastic pipe, OD 4.95 in (13.0 cm), was used to case the hole.

5. The casing was cemented at 200 psi (1,379 kPa) with a cement and fly ash mixture.

6. The cement plug was drilled out of the casing and the core hole with a 4-3/4-in (12.0-cm) bit.

7. The ore-bearing formation was underreamed to 11-in (28.0-cm) diameter.

8. A 2-1/2-in (6.0-cm) stainless steel screen was set below the casing.

9. Airlifting was done to clean out the well.

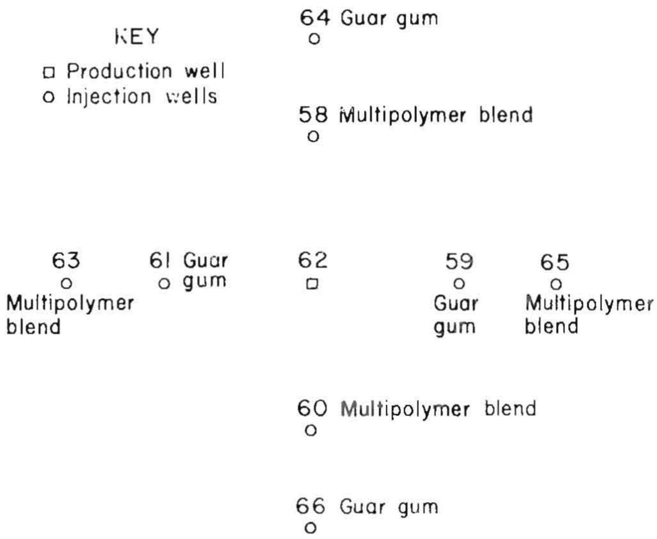

FIGURE 3. - Overlapping five-spot pattern showing which underreaming fluids were used.

Each hole was supposed to be drilled, cored, reamed, and underreamed (steps 1, 2, 3, and 7) with the particular drilling fluid. However, after drilling and reaming two wells with the multipolymer blend and one with the guar gum, it was found that swelling clays caused casing problems. It was extremely difficult to lower the plastic casing into the hole because it would hang up on the oversize joints. At this point it was decided to use a shale-inhibiting synthetic polymer for the drilling, coring, and reaming and use the test fluid only for the underreaming. This arrangement worked well in that no more casing problems were encountered. Potassium chloride was not used to control the clays because it would have interfered with the background chloride level concentration used for environmental monitoring. The types and Marsh funnel viscosity of drilling fluids used for drilling, coring, and reaming are shown in table 6. The casing was cemented, and 3 days were allowed for curing before underreaming was done.

The guar gum or multipolymer blend drilling fluids were mixed in 400-gal (1,500-L) portable mud pits for the underreaming in the ore zone. Mixing was done by slowly sprinkling the powdered polymer into the discharge from the pump that was used to circulate the fluid in the pit until the fluid reached a viscosity of 35 funnel seconds. This was about 1.4 lb/bbl for both the guar gum and the multipolymer blend.

The cement plug was drilled out of the casing and core hole to allow clearance for the underreamer. A blade-type underreamer then cut through the ore zone. After the screen was set, the well was airlifted until the discharge water became clear (about 1/2 h). No gravel packing was done around the screen, and no breakers were added to the drilling fluid system.

During the completion of wells 58, 60, and 65 the viscosity of the drilling fluid was difficult to maintain at 35 funnel seconds. More of the polymer was needed to maintain the desired viscosity. It was discovered during completion of well 66 that the water in the well casing had a pH of 8.5. This high a pH will impede polymer hydration and will result in a lower viscosity for a given amount. Since the ground water pH at Nine Mile

TABLE 6. - Well completion data

Well	Drilling and reaming		Underreaming		
	Type of fluid	Marsh funnel viscosity, s	Depth, ft	Type of fluid	Marsh funnel viscosity, s
58...	Multipolymer blend	45	445.9-451.1	Multipolymer blend	33
59...	Synthetic polymer.	30	449.1-454.1	Guar gum..........	32
60...	Multipolymer blend	35	445.9-452.4	Multipolymer blend	35
61...	Synthetic polymer.	30	445.9-451.1	Guar gum..........	33
63...	...do.............	30	446.9-452.1	Multipolymer blend	33
64...	...do.............	30	446.9-452.1	Guar gum..........	34
65...	...do.............	30	448.2-453.1	Multipolymer blend	34
66...	Guar gum..........	50	448.2-453.1	Guar gum..........	40

Lake is 6.7, the cement-fly ash mixture used for cementing the well probably caused the higher pH level. The solution to this problem was to pump fresh ground water down the hole until it replaced the high-pH water. This high-pH water was discarded before the mixing of the drilling fluid proceeded. The loss of viscosity then ceased to be a problem.

INJECTION TEST EQUIPMENT AND PROCEDURE

A test was run on the eight injection wells to determine if there was a difference in injection rates between the wells underreamed with guar gum and those underreamed with the multipolymer blend. All eight wells were tested simultaneously. Ground water was injected at a constant rate of approximately 5 gal/min (19 L/min), and the resulting pressure heads (water level) were monitored in each well. Approximately 40 gal/min (150 L/min) were pumped from the production well during the test.

Turbine-type flowmeters, 3/4 in (1.9 cm) in diameter, monitored the injection rate into each well. These meters had a field readout and were also connected to a master board where the flow rate and total flow were monitored. The meters' accuracy was ± 1.0 pct. A system consisting of pressure transducers and a digital readout which compensated for barometric changes was used to monitor the increase in head. The manufacturer's claimed error for this system was 0.1 pct. Only seven of these transducers were available, so well 65's head was measured by the plumb bob method.

The injection test began 5 days after the completion of the last well and ran for 78 h. Two of the flowmeters malfunctioned the first day. The flowrates to these two wells were checked periodically with a pail and a stopwatch to make sure they were approximately correct. Wells 58 and 59 overflowed and had to be capped to contain the injected water and allow pressure to build.

Head level readings were taken every half hour during the first 6 h, every 3 h for the next 18 h, every 8 h for the next 24 h, and every 5 h during the last 30 h.

FIELD TEST RESULTS

The initial head levels and the average flowrate for each well are shown in table 7. Detailed test data are shown in table A-3 and graphically displayed in figure 4. Figure 4 shows that the change in head from preinjection level for each well stabilized toward the end of the test. The last three readings of table A-3 for each well were averaged to determine H in table 8. To determine the formation permeability at each well for table 8, the following equation (16) was utilized with the assumptions that the cavity tested is the size of the underreaming and the cemented well casing acts as a packer.

$$k = \frac{Q}{2\pi LH} \ln \frac{L}{r},$$

where k = permeability,

Q = average injection flowrate,

L = length of underreaming,

H = stabilized change in head from preinjection level,

and r = radius of underreaming.

Using the premeability results, we can apply the paired Student t tests (17, p. 224), which at the 95-pct confidence level indicate there is no significant difference between the guar gum and multipolymer wells. If we assume from figure 4 that well 59 has failed, invalidating well pair 59 and 65, applying the paired Student t tests to the remaining wells, we again find there is no significant difference between guar gum and multipolymer wells. It must be concluded that within the experimental limits of the field test no significant difference was detected between the two drilling fluids.

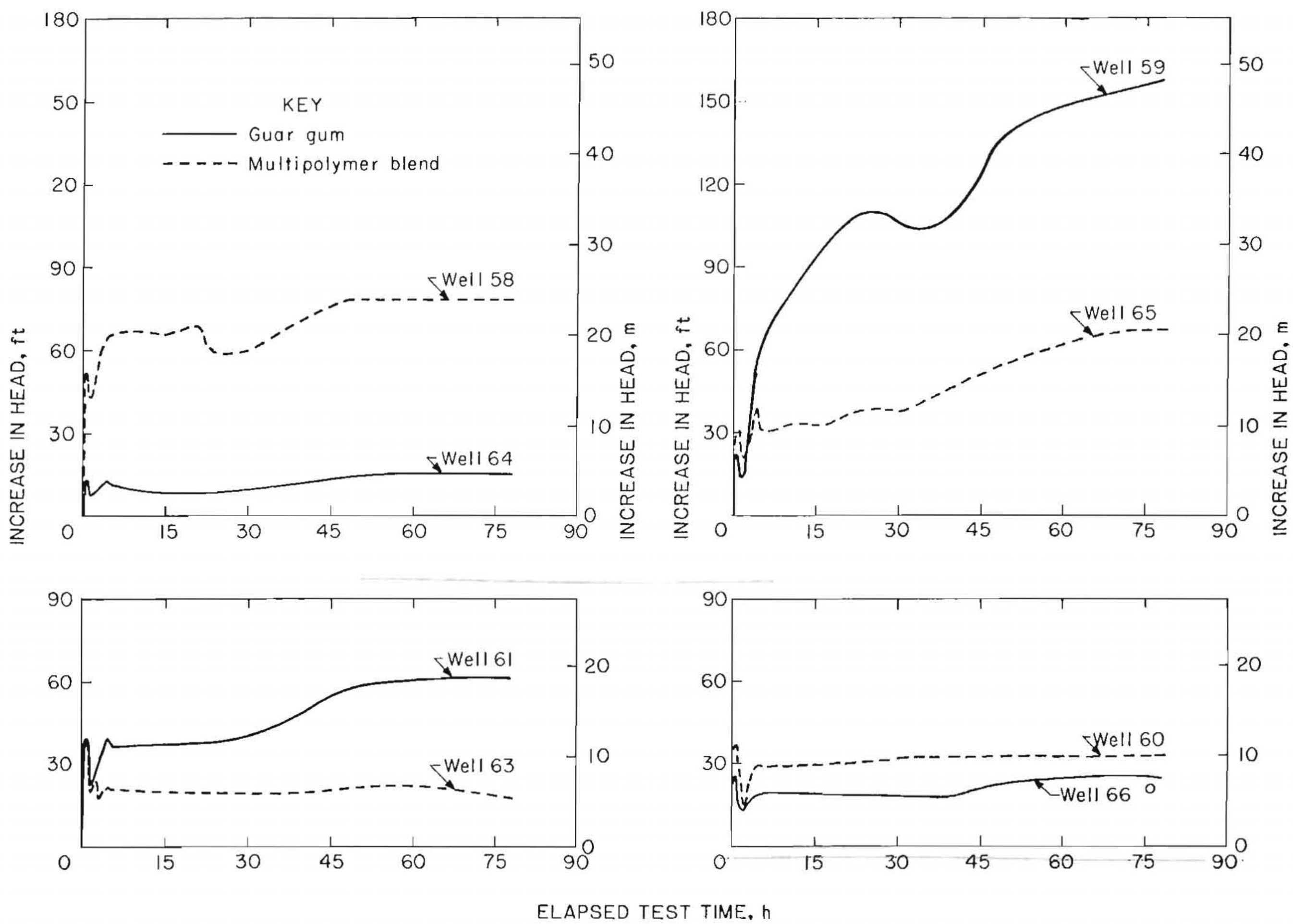

FIGURE 4. - Comparison of change in head with respect to time for each pair of wells.

TABLE 7. - Initial water levels and average injection rates for each well

Well	Initial water level, ft	Average flow, gal/min
58.........	78.5	5.03
59.........	78.0	[1]5.00
60.........	79.2	[1]5.00
61.........	81.0	4.95
63.........	81.5	5.08
64.........	77.5	4.99
65.........	77.4	4.85
66.........	80.0	5.08

[1]Estimated. 2 h after initiation of the test, the flowmeters for well 59 and 60 clogged. A 1-gal bucket was therefore used to periodically check the flows of these wells.

TABLE 8. - Formation permeability at each well

Drilling fluid	Height, ft	k, ft/yr	Permeability, darcy[1]
Guar gum:			
Well 59...	155.8	171	0.174
Well 61...	61.9	428	.432
Well 64...	15.2	1,752	1.769
Well 66...	23.3	1,164	1.176
Multipolymer blend:			
Well 58...	77.8	346	.349
Well 60...	31.0	861	.869
Well 63...	18.4	1,472	1.487
Well 65...	66.4	390	.394

[1]1 darcy = 0.957×10^{-5} m/s (18).

CONCLUSIONS

In laboratory tests on sandstone cores there were significant differences in the permeability damage caused by different types of drilling fluids. The least damage was done by HEC and multipolymer blend polymer fluids, which gave average return permeabilities of 47 and 43 pct, respectively. The most damage was done by synthetic and guar gum polymers and bentonite fluids; these average return permeabilities ranged from 5 to 27 pct. When guar gum and multipolymer blend drilling fluids were compared under identical field drilling conditions of in situ uranium leaching wells, however, no significant differences could be determined from injection rates. This result can be attributed to the fact that field conditions allow the introduction of undesirable foreign matter from numerous relatively uncontrollable sources, and the effect of this foreign matter overshadows the amount of damage done by polymer drilling fluid systems.

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APPENDIX

TABLE A-1. - Clean fluid permeability test results

Initial, darcy	Final, darcy	Return, pct
HYDROXYETHYL CELLULOSE		
0.0150	0.0070	46.75
.0380	.0257	67.52
.0524	.0201	37.13
.0462	.0218	47.22
.0403	.0196	48.61
.0221	.0099	44.79
.0978	.0392	40.02
MULTIPOLYMER BLEND		
0.1749	0.0551	31.50
.0384	.0089	23.07
.1706	.0650	38.10
.0677	.0196	28.96
.0585	.0320	54.69
.5759	.1771	30.75
.3616	.1409	38.97
.2482	.0835	33.64
.0466	.0204	43.74
GUAR GUM 1		
0.4307	0.0774	17.98
.2252	.0619	27.49
.1384	.0334	24.10
.0606	.0068	11.15
.1533	.0086	5.59
.0180	.0018	10.23
.2949	.0617	20.91
.1107	.0226	20.41
.3114	.0366	11.76
.6976	.0729	10.45
.2323	.0461	19.85
.2031	.0433	21.30
.1645	.0447	27.18
.3969	.0621	15.64
BENTONITE + HYDROXYETHYL CELLULOSE		
0.1471	0.0007	0.51
.0065	.0008	12.16
.0228	.0028	12.26
.3301	.0022	.67
.0145	.0008	5.18
.2078	.0010	.49
BENTONITE + HYDROXYETHYL CELLULOSE (1-DAY TEST)		
0.2705	0.0369	13.64
.2526	.0216	8.54
.1862	.0048	2.57
.0623	.0095	15.31
.1854	.0080	4.33
.0159	.0015	9.60
.1137	.0193	16.99

Initial, darcy	Final, darcy	Return, pct
GRAFT CHAIN POLYSACCHARIDE		
0.0349	0.0059	16.86
.1176	.0226	19.19
.0078	.0011	13.42
.0920	.0656	71.34
.0819	.0202	24.69
.0936	.0669	71.54
.1601	.0746	46.58
.1912	.0779	40.73
GUAR GUM 2		
0.2263	0.0423	18.72
.0248	.0048	19.32
.1999	.0581	29.08
.2495	.0533	21.38
.0496	.0142	28.57
XANTHUM GUM		
0.0509	0.0032	6.25
.0231	.0105	45.57
.0143	.0023	15.93
.1583	.1166	73.68
.0434	.0270	62.26
.3229	.1553	48.08
.4494	.1436	31.95
.1997	.1850	92.63
.1775	.0542	30.51
.6666	.2891	43.37
.2895	.1134	39.16
.6163	.2692	43.69
SYNTHETIC POLYMER		
0.1266	0.0006	0.44
.0303	.0023	7.50
.0658	.0030	4.51
.0069	.0003	4.14
.0655	.0058	8.80
BENTONITE (1-DAY TEST)		
0.3606	0.1221	33.85
.0643	.0104	16.21
.0330	.0043	13.02
.0337	.0123	36.56
.0461	.0213	46.19
.1540	.0350	22.69
.3907	.1503	38.46
.1243	.0025	1.99
.0311	.0103	33.20

TABLE A-2. - Dirty fluid permeability test results

Initial, darcy	Final, darcy	Return, pct	Initial, darcy	Final, darcy	Return, pct
HYDROXYETHYL CELLULOSE			GUAR GUM 3		
0.1110	0.0319	28.78	0.1110	0.0159	14.32
.0773	.0368	47.57	.0032	.0001	4.11
.0220	.0020	9.00	.0336	.0007	1.95
.1210	.0348	28.71	.0355	.0015	4.25
.0120	.0012	10.28	.0780	.0042	5.37
MULTIPOLYMER BLEND			XANTHUM GUM		
0.0396	0.0181	45.73	0.1114	0.0035	3.15
.0054	.0019	35.14	.1219	.0080	6.55
.1275	.0510	39.96	.0512	.0034	6.72
.1160	.0494	42.54	.0556	.0055	9.90
.1323	.0693	52.34	.0022	.0001	6.56
GUAR GUM 1			SYNTHETIC POLYMER		
0.0371	0.0019	5.08	0.0203	0.0005	2.53
.0207	.0074	35.98	.0117	.0014	11.89
.0016	.0005	28.58	.0029	.0002	6.06
.0927	.0374	40.32	.0496	.0028	5.65
.1172	.0234	19.98			

TABLE A-3. - Increase in head from preinjection level, feet

Elapsed test time		Well							
Hours	Min	58	64	59	65	60	66	61	63
0	15	6.6	1.8	7.8	NA	3.9	2.7	9.6	9.6
0	20	27.9	4.1	13.3	22.2	21.8	15.6	24.8	23.9
0	35	47.4	10.7	21.1	29.1	33.7	24.7	38.5	29.5
	50	51.6	13.0	21.6	30.1	36.1	25.4	39.6	29.3
1	05	51.6	11.4	19.2	24.9	32.8	19.4	37.5	26.4
	35	43.2	7.2	13.3	22.0	22.1	14.0	24.9	19.4
2	05	44.6	8.9	14.5	23.3	22.5	11.8	25.7	22.1
	35	46.9	8.4	21.4	24.8	17.3	16.0	28.5	24.0
3	05	51.9	9.0	32.1	27.1	20.2	15.6	32.2	18.3
	35	59.0	10.8	42.3	29.6	23.5	17.2	35.1	19.8
4	05	63.3	12.2	NA	31.6	27.9	18.7	37.7	21.0
	35	64.9	12.3	60.9	37.7	29.4	19.3	40.5	21.4
5	15	66.4	12.1	65.6	30.8	29.5	19.7	37.3	21.5
	35	66.1	10.9	61.7	30.1	29.8	20.1	36.0	21.1
6	05	65.8	10.5	64.2	30.2	29.6	19.9	36.3	20.9
6	30	65.8	10.3	66.5	30.3	29.7	19.9	36.6	20.9
9	05	66.5	10.0	NA	31.9	29.5	19.6	37.6	20.7
12	05	66.0	9.8	78.0	33.0	30.6	19.5	38.5	20.6
15	05	64.9	8.2	94.2	32.7	29.1	17.4	37.5	19.2
18	05	NA	NA	101.1	34.0	NA	NA	NA	NA
20	05	67.2	8.6	105.7	34.7	29.9	17.6	36.6	19.1
21	05	69.6	9.8	108.0	36.0	33.6	19.4	65.5	20.9
24	05	59.7	8.9	110.3	37.5	31.1	19.2	40.4	20.7
32	05	60.8	10.5	105.7	37.7	32.0	18.2	40.5	18.2
40	05	71.0	11.6	108.0	46.7	32.2	17.6	50.9	19.1
48	05	77.2	14.8	138.1	53.7	39.3	23.5	56.8	21.2
51	05	77.8	14.6	140.4	55.5	30.4	22.8	59.7	21.4
57	05	77.8	15.4	142.7	58.4	32.2	NA	58.0	22.5
59	05	77.8	15.9	147.3	60.1	32.5	23.9	60.8	22.8
72	05	77.8	17.1	154.2	66.3	33.5	24.9	63.5	20.1
76	05	77.8	13.2	156.5	65.8	29.8	20.4	59.5	16.4
78	05	77.8	15.3	156.5	67.2	31.8	24.7	62.7	18.8

NA Not available. Due to technical difficulties data were not recorded.

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